COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

AT RICHMOND, NOVEMBER 12, 2008

COMMONWEALTH OF VIRGINIA, *ex rel*.

STATE CORPORATION COMMISSION

CASE NO. PUE-2008-00099

Concerning Electric Utility Integrated
Resource Planning Pursuant
to §§ 56-597 *et seq.* of the Code of Virginia

ORDER PROPOSING GUIDELINES AND DIRECTING
THE FILING OF INTEGRATED RESOURCE PLANS

Pursuant to § 56-599 of the Code of Virginia ("Code"), the State Corporation Commission ("Commission") is required to issue an order no later than December 31, 2008, directing each investor-owned electric utility to develop and file an integrated resource plan ("IRP"). As defined by § 56-597 of the Code, an IRP is "a document developed by an electric utility that provides a forecast of its load obligations and a plan to meet those obligations by supply side and demand side resources over the ensuing 15 years to promote reasonable prices, reliable service, energy independence, and environmental responsibility." The contents of an IRP to be submitted by an electric utility are set forth in § 56-598 of the Code. Pursuant to the second enactment clauses in Chapters 476 and 603 of the 2008 Virginia Acts of Assembly, as part of its 2009 IRP, "each electric utility shall assess governmental, nonprofit, and utility programs in its service territory to assist low income residential customers with energy costs and shall examine, in cooperation with relevant governmental, nonprofit, and private sector stakeholders, options for making any needed changes to such programs." Section 56-599 D of the Code provides a list of alternatives that each electric utility must systematically evaluate in preparing its IRP.

Presently operating in the Commonwealth as investor-owned electric utilities are the following companies: Appalachian Power Company, Kentucky Utilities Company d/b/a Old Dominion Power Company, The Potomac Edison Company d/b/a Allegheny Power, and Virginia Electric and Power Company d/b/a Dominion Virginia Power.

In accordance with § 56-599 of the Code, the Commission hereby orders that each electric utility listed above shall develop its individual IRP, and each shall file its initial IRP with this Commission by September 1, 2009. Upon the filing of the IRP by each electric utility, a separate and new docket will be opened wherein the Commission will analyze and review each IRP and, after giving notice and an opportunity to be heard, will make a determination as to whether the individual IRP is reasonable and is in the public interest, as required by Code § 56-599 E.

Section 56-599 A of the Code provides that the Commission may establish guidelines for developing an IRP. The Commission Staff has prepared proposed guidelines for each electric utility to use in developing its IRP. A draft of the proposed guidelines is attached for review and comment by interested persons. Each electric utility IRP filing should be in accordance with the guidelines, once established by further order of the Commission, and must be in compliance with the statutory directives set forth by the General Assembly. The Commission will receive comments on the proposed guidelines from interested persons before formally establishing Commission guidelines pursuant to § 56-599 A of the Code. Comments on the proposed guidelines may be filed in the proceeding within thirty (30) days from the date of this Order.

In order to promote broad dissemination of the proposed guidelines, we direct the Commission's Division of Economics and Finance to provide copies of this Order and the proposed guidelines by electronic transmission, or when electronic transmission is not possible, by mail, to individuals, organizations, and companies identified by Staff as potentially having an interest in this proceeding.

Accordingly, IT IS ORDERED THAT:

(1) This matter is docketed and assigned Case No. PUE-2008-00099.

(2) Appalachian Power Company, Kentucky Utilities Company d/b/a Old Dominion Power Company, The Potomac Edison Company d/b/a Allegheny Power, and Virginia Electric and Power Company d/b/a Dominion Virginia Power shall each file with the Clerk of the Commission, in conformity with the Commission's Rules of Practice and Procedure, an initial IRP by September 1, 2009.

(3) Simultaneous with the filing as directed above, each such electric utility shall provide a copy of its IRP filed with the Commission to the chairmen of the House Committee on Commerce and Labor, the Senate Committee on Commerce and Labor, and the Commission on Electric Utility Regulation,[1] as required by the third enactment clauses in Chapters 476 and 603 of the 2008 Virginia Acts of Assembly.

(4) Comments on the proposed guidelines shall be filed on or before thirty (30) days from the date of this Order. Interested persons wishing to comment, propose modifications or supplements to the proposed guidelines shall file an original and fifteen (15) copies of such comments or proposals with the Clerk of the Commission, P.O. Box 2118, Richmond, Virginia 23218, making reference to Case No. PUE-2008-00099, or by following the Commission's rules for electronic filing pursuant to 20 VAC 5-20-140 of the Commission's Rules of Practice and Procedure. Comments may also be submitted electronically by following the instructions available at the Commission's website: http://www.scc.virginia.gov/case.

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[1] The name of the Commission was changed from the Commission on Electric Utility Restructuring by the General Assembly pursuant to Chapter 883 of the 2008 Virginia Acts of the Assembly.

(5) The Commission's Division of Information Resources shall make a downloadable version of the proposed guidelines available for access by the public at the Commission's website: http://www.scc.virginia.gov/case. The Clerk of the Commission shall make a copy of the proposed guidelines available, free of charge, in response to any written request for one.

(6) The Commission's Division of Economics and Finance shall transmit electronically or by mail a copy of the Order and proposed guidelines to individuals, organizations, and companies identified by Staff as potentially having an interest in this proceeding.

(7) This matter is continued for further orders of the Commission.

AN ATTESTED COPY shall be sent by the Clerk of the Commission to: Appalachian Power Company, P.O. Box 2021, Roanoke, Virginia 24022-2121; Kentucky Utilities Company d/b/a Old Dominion Power Company, 220 West Main Street, P.O. Box 32010, Louisville, Kentucky 40232; The Potomac Edison Company d/b/a Allegheny Power, 800 Cabin Hill Road, Greensburg, Pennsylvania 15601; Virginia Electric and Power Company d/b/a Dominion Virginia Power, P.O. Box 26532, Richmond, Virginia 23261-6532; Robert A. Vanderhye, Public Policy Virginia, Inc., 801 Ridge Drive, McLean, Virginia 22101; Peter E. Meier, General Counsel, Pepco Energy Services, 1300 17th Street, North, Suite 1600, Arlington, Virginia 22209-3807; Michael A. King, President, Old Mill Power Company, 2530 Wyngate Road, Charlottesville, Virginia 22901; Louis R. Monacell, Esquire, and Edward L. Petrini, Esquire, Christian & Barton, L.L.P., 909 East Main Street, Suite 1200, Richmond, Virginia 23219-3095; Irene Leech, President, Virginia Citizens Consumer Council; 4220 North Fork Road, Elliston, Virginia 24087; C. Meade Browder, Jr., Senior Assistant Attorney General, Division of Consumer Counsel, Office of Attorney General, 900 East Main Street, 2nd Floor, Richmond, Virginia 23219; Franklin Munyan, Esquire, Legislative Services, 910 Capitol Street, Richmond, Virginia 23219; and the Commission's Office of General Counsel and Divisions of Public Utility Accounting, Economics and Finance, and Energy Regulation.

INTEGRATED RESOURCE PLANNING GUIDELINES

Purpose. The purpose of these guidelines is to implement the provisions of §§ 56-597, 56-598 and 56-599 of the Code of Virginia with respect to integrated resource planning ("IRP") by the electric utilities in the Commonwealth. In order to understand the basis for the utility's plan, the IRP filing shall include a narrative summary detailing the underlying assumptions reflected in its forecast as further described in the guidelines. To better follow the utility's planning process, the narrative shall include a description of the utility's rationale for the selection of any particular generation addition or demand-side management program to fulfill its forecasted need. Such description should include the utility's evaluation of its purchase options and cost/benefit analyses for each resource option to confirm and justify each resource option it has chosen. Such narrative shall also describe the planning process including timelines and appropriate reviews and/or approvals of the utility's plan. For members of PJM Interconnection, LLC ("PJM"), the narrative should describe how the IRP integrates into the planning process of PJM's Regional Transmission Expansion Plan and how it will satisfy PJM load obligations.

These guidelines also include sample schedules to supplement this narrative discussion and assist the utilities in developing a tabulation of the utility's forecast for at least a 15-year period and identify the projected supply-side or demand-side resource additions and solutions to adequately and reliably meet the electricity needs of the Commonwealth. This tabulation shall also indicate the projected effects of demand response and energy efficiency programs and activities on forecasted annual energy and peak loads for the same period. These guidelines also direct that all IRP filings include information to comparably evaluate various supply-side technologies and demand-side programs and technologies on an equivalent basis. The Commission may revise or supplement the sample schedules as needed or warranted.

Applicability. These guidelines are applicable to all investor-owned utilities responsible for procurement of any or all of its individual power supply resources.

Integrated Resource Plan. Each utility shall develop and keep current an integrated resource plan, which incorporates, at a minimum, the following:

1. Forecast. A three-year historical record and a 15-year forecast of the utility's native load requirements, the utility's PJM load obligations if appropriate, and other system capacity or firm energy obligations for each peak season along with the supply-side (including owned/leased generation capacity and firm purchased power arrangements) and demand-side resources expected to satisfy those loads, and the reserve margin thus produced.

2. Option analyses. A comprehensive analysis of all existing and new resource options (supply- and demand-side) considered and chosen by the utility for satisfaction of native load requirements and other system obligations necessary to provide reliable electric utility service, preferably at least cost, over the planning period.

a. Purchased Power – assess the potential costs and benefits of soliciting proposals from wholesale power suppliers and power marketers to supply it with needed capacity and describe in detail any decision to purchase electricity from the wholesale power market.

b. Supply-side Energy Resources - assess the potential costs and benefits of reasonably available traditional and alternative supply-side energy resource options, including, but not limited to technologies such as, nuclear, pulverized coal, clean coal, circulating fluidized bed, wood, combined cycle, integrated gasification combined cycle, and combustion turbine, as well as renewable energy resources derived from sunlight, wind, falling water, sustainable biomass, energy from waste, municipal solid waste, wave motion, tides, and geothermal power.

c. Demand-side Options - assess programs to promote demand-side management, including costs, benefits, risks, uncertainties, reliability, and customer acceptance where appropriate. For purposes of these guidelines, peak reduction and demand response programs and energy efficiency and conservation programs will collectively be referred to as demand-side options.

d. Evaluation of Resource Options - analyze potential resource options and combinations of resource options to serve system needs, taking into account the sensitivity of its analysis to variations in future estimates of peak load, energy requirements, and other significant assumptions, including, but not limited to, the risks associated with wholesale markets, fuel costs, construction or implementation costs, transmission and distribution costs, environmental impacts and compliance costs, system operations, and other qualitative factors.

Narrative Summary. Each utility shall provide a narrative summary detailing the major trends, events, and/or conditions reflected in the forecasted data submitted in response to these guidelines. Examples of items which should be highlighted in the summary include:

1. Discussion regarding the forecasted peak load obligation and energy requirements. PJM members should also discuss the relationship of the utility's expected non-coincident peak and its expected PJM related load obligations.

2. Discussion regarding company goals and plans in response to directives of Chapters 23 and 24 of Title 56 of the Code of Virginia, including compliance with energy efficiency, energy conservation, demand-side and response programs, and the provision of electricity from renewable energy resources.

3. Discussion regarding the complete planning process, including timelines, assumptions, reviews, approvals, etc., of the company's plans. For PJM members, the discussion should also describe how the IRP integrates into the complete planning process of PJM.

4. Robustness of the critical input assumptions to determine the forecast and expected changes in load growth including factors such as energy conservation, efficiency, load management, demand response, variations in customer class sizes, expected levels of economic activity, variations in fuel prices and appliance stocks, etc. Discussion regarding cost/benefit analyses and the results of such factors on this plan, including the methodology used to consider equal or comparable treatment afforded both the demand-side options and supply-side resources.

5. Planned changes in operating characteristics such as unit retirements, unit uprates or derates, changes in unit availabilities, changes in capacity resource mix, changes in fuel supplies or transport, emissions compliance, unit performance, etc.

6. Discussion regarding the effectiveness of the utility's IRP to meet its load obligations with supply-side and demand-side resources to enable the utility to provide reliable service at reasonable prices over the long term.

Filing. By September 1, 2009, and every two years thereafter, each utility shall file with the Commission its then current integrated resource plan, which shall include all information required by these guidelines for the ensuing 15-year planning period along with the prior three-year historical period. The process and analyses shall be described in a narrative discussion and the results presented in tabular format using an EXCEL spreadsheet format, similar to the attached sample schedules, and be provided in both printed and electronic media. For those utilities that operate as part of a multi-state integrated power system, the schedules should be submitted both on an individual company and a total system basis. The top line stating the company name should indicate that the data reflects the individual utility company or the total system. For partial ownership of any facility, please provide the percent ownership and footnote accordingly.

Each filing shall include a five-year action plan that discusses those specific actions currently being taken by the utility to implement the options or activities chosen as appropriate per the IRP. If a utility considers certain information in its IRP to be proprietary or confidential, the utility may so designate, file separately and request such treatment in accordance with the Commission's Rules of Practice and Procedures.

Additionally, by September 1 of each year in which a plan is *not* required, each utility shall file a narrative summary describing any significant event necessitating a major revision to the most recently filed IRP, including adjustments to the type and size of resources identified.

As § 56-599 E requires the giving of notice and an opportunity to be heard, each utility shall also include a copy of its proposed notice to be used to afford such an opportunity.

Contents of Filing. The IRP shall include the following data:

1. Forecast of Load. The forecast shall include descriptions of the methods, models, and assumptions used by the utility to prepare its forecasts of its loads, requirements associated with the utility's PJM load obligation (MW) if appropriate, the utility's peak load (MW) and energy sales (MWh) and the variables used in the models and shall include, at a minimum, the following:

a. The most recent three-year history and 15-year forecast of energy sales (kWh) by each customer class,

b. The most recent three-year history and 15-year forecast of the utility's peak load and the expected load obligation to satisfy PJM's coincident peak forecast if appropriate, and the utility's raw, and likely non-coincident, peak loads for summer and winter seasons of each year (prior to any DSM), annual energy forecasts, and resultant reserve margins. The tabulation shall also indicate the projected effects of demand-side options on the forecasted annual energy and peak loads, and

c. Where future resources are required, a description and associated characteristics of the option that the utility proposes to use to address the forecasted need.

2. Supply-side Resources. The forecast shall provide data for its existing and planned electric generating facilities (including planned additions and retirements and rating changes, as well as firm purchase contracts, including cogeneration and small power production):

a. Existing Generation. For existing units in service:

i. Type of fuel(s) used;

ii. Type of unit (e.g., base, intermediate, or peaking);

iii. Location of each existing unit;

iv. Commercial Operation Date;

v. Size (nameplate, dependable operating capacity, and expected capacity value to meet load obligation (MW));

vi. Units to be placed in reserve shutdown or retired from service with expected date of shutdown or retirement;

vii. Units with specific plans for life extension, refurbishment, fuel conversion, or upgrading. The reporting utility shall also provide the expected (or actual) date removed from service, expected return to service date, capacity rating upon return to service, and a general description of work to be performed;

viii. Other changes to existing generating units that are expected to increase or decrease generation capability of such unit; and

ix. A narrative description of the driver(s) underlying such anticipated changes such as expected environmental compliance, carbon restrictions, technology enhancements, etc.

b. Assessment of Supply-side Resources. Include the current overall assessment of existing and potential traditional and alternative supply-side energy resources, including a descriptive summary of each analysis performed or used by the utility in the assessment. The utility shall also provide general information on any changes to the methods and assumptions used in the assessment since its most recent IRP or annual report.

i. For the currently operational or potential future supply-side energy resources included, provide information on the capacity and energy available or projected to be available from the resource and associated costs. The utility shall also provide this information for any actual or potential supply-side energy resources that have been discontinued from its plan since its last biennial report and the reasons for that discontinuance.

ii. For supply-side energy resources evaluated but rejected, a description of the resource; the potential capacity and energy associated with the resource; associated costs and the reasons for the rejection of the resource.

c. Planned Generation Additions. A list of planned generation additions, the rationale as to why each listed generation addition was selected, and a 15-year projection of the following for each listed addition:

i. Type of conventional or alternative facility and fuel(s) used;

ii. Type of unit (e.g. baseload, intermediate, peaking);

iii. Location of each planned unit, including description of locational benefits identified by PJM and/or the utility;

iv. Expected Commercial Operation Date;

v. Size (nameplate, dependable operating capacity, and expected capacity value to meet load obligation (MW));

vi. Summaries of the analyses supporting such new generation additions, including its type of fuel and designation as base, intermediate, or peaking capacity.

vii. Cost of planned unit additions to compare with demand-side options.

d. Non-Utility Generation. A separate list of all non-utility electric generating facilities included in the IRP, including customer-owned and stand-by generating facilities. This list shall include the facility name, location, primary fuel type, and contractual capacity (including any contract dispatch conditions or limitations), and the contractual start and expiration dates. The utility shall also indicate which facilities are included in their total supply of resources.

3. Capacity Position. Provide a narrative discussion and tabulation reflecting the capacity position of the utility in relation to satisfying PJM's load obligation, similar to Schedule 16 of the attached schedules.

4. Wholesale Contracts for the Purchase and Sale of Power. A list of firm wholesale purchased power and sales contracts reflected in the plan, including the primary fuel type, designation as base, intermediate, or peaking capacity, contract capacity, location, commencement and expiration dates, and volume.

5. Demand-side Options. Provide the results of its overall assessment of existing and potential demand-side option programs, including a descriptive summary of each analysis performed or used by the utility in its assessment and any changes to the methods and assumptions employed since its last IRP. Such descriptive summary, and corresponding schedules, shall clearly identify the total impact of each DSM program.

6. Evaluation of Resource Options. Provide a description and a summary of the results of the utility's analyses of potential resource options and combinations of resource options performed by it pursuant to these guidelines to determine its integrated resource plan.

7. Comparative Costs of Options. Provide detailed information on levelized busbar costs, annual revenue requirements or equivalent methodology for various supply-

side options and demand-side options to permit comparison of such resources on equitable footing. Such data should be tabulated and at a minimum, reflect the resource's heat rate, variable and fixed operating maintenance costs, expected service life, overnight construction costs, fixed charged rate, and the basis of escalation for each component.

COMPANY NAME: ______________________________ **Schedule 1**

I. PEAK LOAD AND ENERGY FORECAST

	(ACTUAL)			(PROJECTED)														
	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
PJM Load Obligation (if appropriate)																		
1. Utility Peak Load (MW)																		
A. Summer																		
1. Base Forecast																		
2. Conservation, Efficiency																		
3. Demand-side and Response																		
4. Adjusted Load																		
5. % Increase in Adjusted Load (from previous year)																		
B. Winter (1)																		
1. Base Forecast																		
2. Conservation, Efficiency																		
3. Demand-side and Response																		
4. Adjusted Load																		
5. % Increase in Adjusted Load (from previous year)																		
2. Energy (GWH)																		
A. Base Forecast																		
B. Conservation, Efficiency																		
C. Demand-side and Response																		
D. Adjusted Energy																		
E. % Increase in Adjusted Energy (from previous year)																		

(1) 2006 data refers to winter season 2005/2006, 2007 data refers to winter season 2006/2007, etc.

COMPANY NAME: ______________________________ Schedule 2

GENERATION

	(ACTUAL)			(PROJECTED)														
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
I. System Output (GWh)																		
a. Nuclear																		
b. Coal																		
c. Heavy Fuel Oil																		
d. Light Fuel Oil																		
e. Natural Gas																		
f. Hydro-Conventional																		
g. Hydro-Pumped Storage																		
h. Renewable Resources																		
i. Total Generation (sum of a through h)																		
j. Purchased Power																		
1. Firm																		
2. Other																		
k. Less Pumping Energy																		
l. Less Other Sales (1)																		
m. Total System Firm Energy Requirements																		
II. Energy Supplied by Competitive Service Providers																		

* In the event that a unit uses multiple fuels for generation (alternate fuel) allocate generation accordingly; ignition and flame stabilization fuels are not considered to be fuel for generation.

(1) To include all sales or delivery transactions with other electric utilities, i.e., firm sales, diversity exchange, etc.

COMPANY NAME: ______________________

Schedule 3

GENERATION

	(ACTUAL)			(PROJECTED)														
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
III. System Output Mix(%)																		
a. Nuclear																		
b. Coal																		
c. Heavy Fuel Oil																		
d. Light Fuel Oil																		
e. Natural Gas																		
f. Hydro-Conventional																		
g. Hydro-Pumped Storage																		
h. Renewable Resources																		
i. Total Generation (sum of a through g)																		
j. Purchased Power																		
1. Firm																		
2. Other																		
k. Less Pumping Energy																		
l. Less Other Sales (1)																		
IV. System Load Factor																		

COMPANY NAME: ____________________

Schedule 4

POWER SUPPLY DATA

	(ACTUAL)			(PROJECTED)														
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
I. Capability (MW)																		
1. Summer																		
a. Installed Net Dependable Capability (1)																		
b. Total Positive Interchange Commitments(2)																		
c. Capability in Cold Reserve/ Reserve Shutdown Status(1)																		
d. Demand-side and Response																		
e. Total Net Summer Capability (a+b+c+d)																		
2. Winter (3)																		
a. Installed Net Dependable Capability (1)																		
b. Total Positive Interchange Commitments (2)																		
c. Capability in Cold Reserve Status (1)																		
d. Demand-side and Response																		
e. Total Net Winter Capability (a+b+c+d)																		

(1) Provide Net Seasonal Capability.

(2) To include firm commitments for the receipt of specified blocks of power (i.e., unit power, limited term, diversity exchange, cogeneration, small power production, etc.)

(3) 2006 data refers to winter of 2005/2006, 2007 data refers to winter of 2006/2007, etc.

COMPANY NAME: ______________________________ **Schedule 5**

POWER SUPPLY DATA (continued)

	(ACTUAL)			(PROJECTED)														
II. Load (MW)	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
1. Summer																		
a. Adjusted Summer Peak(1)																		
b. Total Negative Power Commitments(2)																		
c. Total Summer Peak																		
d. Percent Increase in Total Summer Peak																		
2. Winter (3)																		
a. Adjusted Winter Peak(1)																		
b. Total Negative Power Commitments (2)																		
c. Total Winter Peak																		
d. Percent Increase in Total Winter Peak																		

(1) Peak after energy efficiency and demand-side programs, see page 1.

(2) To include firm commitments for the delivery of specified blooks of power (i.e., unit power, limited term, diversity exchange, etc.).

(3) 2006 data refers to winter of 2005/2006, 2007 data refers to winter of 2006/2007, etc.

COMPANY NAME: ______________________________ Schedule 6

POWER SUPPLY DATA (continued)

	(ACTUAL)			(PROJECTED)														
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
I. Reserve Margin (Including Cold Reserve Capability)(1)																		
1. Summer Reserve Margin																		
a. MW																		
b. Percent of Load																		
2. Winter Reserve Margin (2)																		
a. MW																		
b. Percent of Load																		
II. Reserve Margin (Excluding Cold Reserve Capability)(3)																		
1. Summer Reserve Margin																		
a. MW																		
b. Percent of Load																		
2. Winter Reserve Margin (2)																		
a. MW																		
b. Percent of Load																		
III. Annual Loss-of-Load Hours																		

(1) To be calculated based on Total Net Capability for summer and winter.
(2) 2006 data refers to winter of 2005/2006, 2007 data refers to winter of 2006/2007,etc.
(3) Same as footnote 1 above less capability in cold reserve.

COMPANY NAME: ______________________________ Schedule 7

CAPACITY DATA

	(ACTUAL)			(PROJECTED)														
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
I. Installed Capacity(MW) (1)																		
a. Nuclear																		
b. Coal																		
c. Heavy Fuel Oil																		
d. Light Fuel Oil																		
e. Natural Gas																		
f. Hydro-Conventional																		
g. Pumped Storage																		
h. Renewable																		
i. Total (sum of a through h)																		
II. Installed Capacity Mix (%)(2)																		
a. Nuclear																		
b. Coal																		
c. Heavy Fuel Oil																		
d. Light Fuel Oil																		
e. Natural Gas																		
f. Hydro-Conventional																		
g. Pumped Storage																		
h. Renewable																		

(1) Net dependable installed capability during peak season; unit capabilities to be classified by primary fuel type; for winter peaking utilities - 2006 refers to the winter of 2006/2007, etc.

(2) Each item in Section I as a percent of line i (total).

COMPANY NAME: ______________________________ Schedule 8

UNIT PERFORMANCE DATA (1)

Equivalent Availability Factor (%)

	(ACTUAL)			(PROJECTED)														
Unit Name	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023

(1) Combustion turbines to be reported as a composite facility.

Note: Copy as needed for additional units.

COMPANY NAME: ______________________________

Schedule 9

UNIT PERFORMANCE DATA (1)

Net Capacity Factor (%)

	(ACTUAL)			(PROJECTED)														
Unit Name	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**

(1) Combustion turbines to be reported as a composite facility.

Note: Copy as needed for additional units.

COMPANY NAME: ______________________ Schedule 10

UNIT PERFORMANCE DATA (1)

Average Heat Rate - (Btu/kWh)

	(ACTUAL)			(PROJECTED)														
Unit Name	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**

(1) Combustion turbines to be reported as a composite facility.

Note: Copy as needed for additional units.

COMPANY NAME: ______________________________ Schedule 11

RENEWABLE RESOURCES (MWh)

						(ACTUAL)			(PROJECTED)														
Resource Type(1)	Unit Name	C.O.D.(2)	Build/ Purchase(3)	Life/ Duration(4)	Size MW (5)	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
sub-total																							
sub-total																							
sub-total																							
sub-total																							
Total Renewables																							

(1) Per definition of §56-576 of the code of Virginia.

(2) Commercial operation date.

(3) Describe as Company built or purchase.

(4) State expected life of facility or duration of purchase contract.

(5) Net dependable capability.

Note: Copy as needed for additional units.

COMPANY NAME: ____________________

Schedule 12

Energy Efficiency/Conservation/Demand Side Management/Demand Response (MWh)

Program Type(1)	Program Name	Date (2)	Life/ Duration(3)	Size MW (4)	(ACTUAL) 2006	2007	2008	(PROJECTED) 2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
sub-total																						
sub-total																						
sub-total																						
sub-total																						
Total Renewables																						

(1) List each program within the 2 major categories of energy efficiency/conservation/consumption reduction and demand response/peak reduction. Additionally, in the notes provide a description of each.

(2) Implemetation date.

(3) State expected life of facility or duration of purchase contract.

(4) Attributable capability and describe in the notes when such reductions are available, i.e.: at peak, all hours, on-peak hours, etc.

Note: Copy as needed for additional resources.

COMPANY NAME: ______________________ Schedule 13

UNIT PERFORMANCE DATA (1)

Unit Size (MW) Uprate and Derate

	(ACTUAL)			(PROJECTED)														
Unit Name	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023

(1) Combustion turbines to be reported as a composite facility.

(2) Commercial operation date.

(3) Peak net dependable capability as of filing. Incremental Uprates shown as positive (+) and decremental Derates shown as negative (-).

Note: Copy as needed for additional units.

COMPANY NAME: ______________________________ Schedule 14

UNIT PERFORMANCE DATA (1)

Existing Supply-side Resources (MW)

Unit Name	Location	Unit Type	Primary Fuel Type	C.O.D.(2)	Size MW (3)

(1) Combustion turbines to be reported as a composite facility.
(2) Commercial operation date.
(3) Peak net dependable capability as of filing.
Note: Copy as needed for additional units.

COMPANY NAME: ______________________________

Schedule 15

UNIT PERFORMANCE DATA (1)

Planned Supply-side Resources (MW)

Unit Name	Location	Unit Type	Primary Fuel Type	C.O.D.(2)	Size MW (3)

(1) Combustion turbines to be reported as a composite facility.
(2) Commercial operation date.
(3) Peak net dependable capability as of filing.
Note: Copy as needed for additional units.

COMPANY NAME: ______________________ Schedule 16

UTILITY CAPACITY POSITION (MW)

	(ACTUAL)			(PROJECTED)														
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Existing Capacity																		
Conventional																		
Renewable																		
Total Existing Capacity																		
Planned Capacity Changes																		
Conventional																		
Renewable																		
Total Planned Capacity Changes																		
Expected New Capacity																		
Conventional																		
Renewable																		
Total Expected New Capacity																		
Unforced Availability																		
Net Generation Capacity																		
Existing DSM Reductions																		
Demand response																		
Conservation/Efficiency																		
Total Existing DSM Reductions																		
Expected New DSM Reductions																		
Demand response																		
Conservation/Efficiency																		
Total Expected New DSM Reductions																		
Total Demand-side Reductions																		
Net Generation & Demand-side																		
Capacity Requirement or PJM Capacity Obligation																		
Net Utility Capacity Position																		

COMPANY NAME: ______________________

Schedule 17

CONSTRUCTION FORECAST (Million Dollars)

		ACTUAL EXPENDITURES			PROJECTED EXPENDITURES														
		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
I.	**New Traditional Generating Facilities**																		
	a. Capital Investment (Exclusive of AFUDC)																		
	b. AFUDC																		
	c. Annual Total																		
	d. Cumulative Total																		
II.	**New Renewable Generating Facilities**																		
	a. Capital Investment (Exclusive of AFUDC)																		
	b. AFUDC																		
	c. Annual Total																		
	d. Cumulative Total																		
III.	**Other Facilities**																		
	a. Transmission																		
	b. Distribution																		
	c. Energy conservation/efficiency & demand response																		
	c. Other																		
	d. AFUDC																		
	e. Annual Total																		
	f. Cumulative Total																		
IV.	**Total Construction Expenditures**																		
	a. Annual																		
	b. Cumulative																		
V.	**Percent of Funds for Total Construction Provided from External Financing**																		

COMPANY NAME: ____________________

Schedule 18

FUEL DATA

	(ACTUAL)			(PROJECTED)														
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
I. Delivered Fuel Price (cents/MBtu)*																		
a. Nuclear																		
b. Coal																		
c. Heavy Fuel Oil																		
d. Light Fuel Oil																		
e. Natural Gas																		
f. Renewable **																		
II. Primary Fuel Expenses (cents/kWh)*																		
a. Nuclear																		
b. Coal																		
c. Heavy Fuel Oil																		
d. Light Fuel Oil																		
e. Natural Gas																		
f. Renewable**																		
g. Purchases Energy Charges only																		
h. Purchases Energy and Capacity Charges																		

* To include only those components allowed by the Commission's definitional framework of fuel expenses (see Appendix i), except total purchases on line h.

** Per definition of §56-576 of the Code of Virginia.